A Forecast of Cost Effectiveness Avoided Costs and Externality Adders

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Table 1 displays how we have incorporated ATS dimensions of the various avoided costs and adders into our methodology and results. Electric T&D costs vary by utility service territory, planning division and by the 16 CEC Title-24 climate zones used in the CEC's TDV study. The costs of electricity generation and of natural gas procurement, transportation, and delivery vary by utility service territory because such costs do not vary by weather zone. Finally, the estimated costs of environmental externalities, maintaining reliability and the benefit multipliers resulting from price elasticity of demand are uniform across the state.

In addition to variation by area, the estimated avoided costs also vary by time. The avoided costs of electric generation, transmission, and distribution vary by hour, whereas the costs of natural gas procurement, transportation, and delivery vary by month. The price elasticity of demand estimate varies by time-of-use (TOU) period and by month. The cost of maintaining reliability is calculated as annual percentages applied to the hourly energy cost values. The costs of environmental externalities are computed by multiplying the emissions rate of the assumed marginal plant in each hour by a forecasted cost of each pollutant (CO_2, NOx, and PM-10).

TDV Time Dependent Values

ATS Area Time Specific

Table 1: Time and area dimensions of avoided costs and externality adders

Avoided Cost Stream	Time Dimension	Area Dimension
Avoided Electricity Generation	Hourly	Utility specific
Avoided Electric Transmission and Distribution	Hourly	Utility, planning area and climate zone specific
Avoided Natural Gas Procurement	Monthly	Utility specific
Avoided Natural Gas Transportation and Delivery	Monthly	Utility specific
Environmental Externality Adder	Annual value, applied by hour according to implied heat rate	System-wide (uniform across state)
Reliability Adder	Annual value	System-wide (uniform across state)
Price Elasticity of Demand Adder	TOU period (on- vs. off-peak) by month	System-wide (uniform across state)

Any forecast of avoidable electricity and gas costs over a long time horizon will be subject to uncertainty in the underlying cost drivers. Our study addresses this uncertainty in two different ways. First, even though the avoided cost estimates are used for programs with relatively long lives, we recommend frequent updates to the forecasts, perhaps as often as once per year, to reflect changes in important cost drivers. Thus, we have provided a spreadsheet-based model that allows input assumptions to be changed and updated by CPUC staff as conditions warrant. Second, we have developed a separate set of avoided costs for a *stress case* scenario characterized by high gas prices and poor hydro conditions. These avoided costs aim to capture the additional value that dispatchable resources can provide under stress case conditions.

years 2004-2023." (RFP, page 5). E3 developed separate avoided cost price streams for electricity generation (generation emissions) and natural gas combustion (consumption emissions) for use in the overall avoided cost model, as described in Section 2.2. Additionally, our team divided the environmental costs into two categories: (1) "priced" emissions defined as actual costs resulting from emission offset purchases or pollution abatement technologies and (2) "unpriced" emissions defined as environmental externality values. To the extent possible, our methodology for developing these price streams drew upon publicly available observable data to complete transparent calculations of future avoided cost price streams. In this section, we provided an explanation for those calculations or assumptions used in this analysis that are not available in the public domain.

E3's approach to calculating the environmental avoided cost streams is relatively simple. However, the assumptions underlying these calculations are important to fully understand our analyses. Our team calculates the environmental costs by multiplying an average emissions rate for the source - electricity generation plant or the gas end-use - by an average emissions price on a per pollutant basis. The key assumptions in E3's estimation of environmental avoided cost values include the following:

1. Focus on air emissions.

2. Assume gas-fired technologies are at the margin. This is consistent with the other elements of this avoided cost analysis.

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3. Limit analysis to significant emissions. Assuming (1) and (2), the significant emissions that we have included in this analysis are oxides of nitrogen (NOx), particulate matter less than 10 µm (PM-10), and carbon dioxide (CO_2).

We also estimated the marginal emission abatement cost to provide an additional indication of the value of the incremental emissions. Ultimately, our team used the marginal emission abatement technology costs as a bound for the market prices included our analysis as shown in Figure 24. Therefore, the values included in this avoided cost model reflect the average market prices and emissions rates.

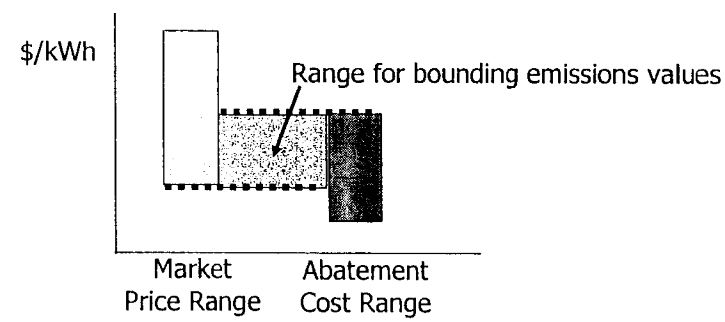

Figure 24: Using Abatement Costs to Bound Emission Market Price Data

2.4.1 Key Findings

The environmental cost chapter's key findings are:

Generation Emissions Findings

(1) The "priced" NOx and PM-10 environmental emission costs are assumed to be embedded in the market prices prior to the resource balance year as described in the Generation Section 2.3.

(2) After the resource balance year, the priced environmental costs are added to the LRMC estimate.

(3) The unpriced emission costs- or externality value of CO_2 - are included as an environmental adder throughout the analysis.

(4) Environmental costs vary by time but locational differences are not included in this estimate.

Natural Gas End-Use Emissions Findings

(1) NOx and CO_2 are included as significant source pollutants but PM-10 was excluded as a significant emission resulting from gas end-use consumption.

(2) Consumption emissions are included in the natural gas combustion avoided costs as unpriced environmental adders throughout all market price periods.

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Table 8 displays a summary of the data and results E3 used to determine the environmental avoided cost values in our model. Each of these components is discussed in detail in this section.

Table 8: Summary of environmental avoided cost components

Model Inputs	Dimension	2004 (Initial) Value	Data Sources	Major Assumptions / Notes	Resulting Output applied in Model
NOx Market Prices	Annual ($/lb)	$3.50/lb NOx	South Coast Air Quality Management District (SCAQMD) - RECLAIM Data	Assumed market prices apply to all of California	$/MWh
PM-10 Market Prices	Estimated Annual ($/lb)	$4.90/lb NOx	California Air Resources Board (CARB)	Estimated using CARB ERCs and RECLAIM Prices	$/MWh
CO2 Market Prices	Estimated Annual ($/lb)	$0.004/lb CO2	Existing International Markets, Oregon Climate Trust, Utility Planning Documents, Models	Used US and International market estimates to calculate future CO2 emission costs	$/MWh
Emission Factors	lb/MMBtu	Varies. See individual pollutant discussions below.	Environmental Protection Agency (EPA), California Energy Commission (CEC)	Averaged (calculated by electricity generation or natural gas consumption technology)	$/MWh
Abatement Costs	$/pollutant removed	Varies. Value used to test reasonableness of market price data	Industry Reports; Vendors; CARB	Averaged by abatement technology	N/A

2.4.2 Approach to Environmental and Externality Estimates

In contrast to the existing CPUC avoided emissions costs, E3 separates environmental costs into priced and unpriced emissions. The priced emissions refer to those emissions that are regulated and for which energy generators must purchases some type of allowances or credits to offset the impact of the emissions produced from their operations. The unpriced emissions represent an externality that is not presently embedded in energy prices and is added directly to the generation and T&D avoided costs. The steps to calculate the environmental costs are described in detail throughout the remainder of this section, where we discuss emission rates for both generation plants and gas end-use followed by a description of our calculation of emission costs. The

emissions values included in the avoided cost model are the product of the average emission rates during specific hours of the day times the cost of emissions as shown in Figure 25.

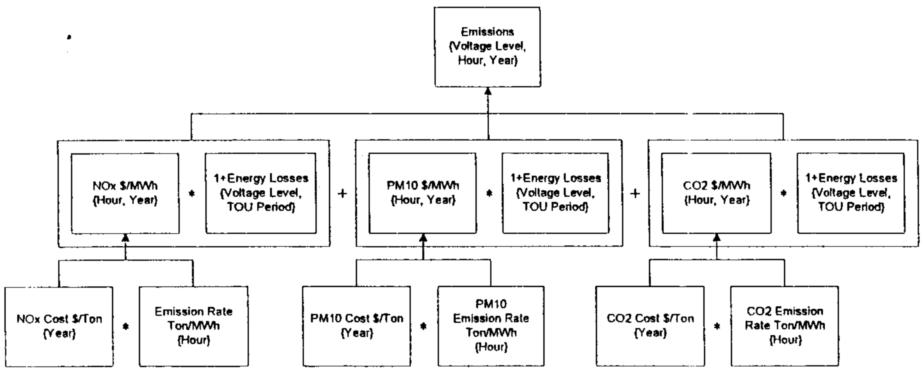

Figure 25: Environmental avoided cost calculation

Before delving into the specifics of each pollutant, it is important to note that our team decided to address environmental costs on a statewide basis rather than incorporate regional price differences. We recognize that regional differences in value exist in different air basins across the state depending upon their air quality attainment status and other pertinent factors. We explored the possibility of modeling these differences. However, given the limited emission cost data available presently, we did not believe we could accurately reflect price differences in this type of modeling effort. In the future, as the California emissions markets become more robust, we would recommend incorporating regional price differences into this model.

2.4.3 Environmental and Externality Estimates

Discussed below is our process to estimate actual environmental costs and environmental externalities. The first half of this section outlines the emissions rates and the second half outlines the emissions costs. We multiplied the emissions rates by the emissions costs to arrive at the environmental avoided cost value streams on a per pollutant basis used in the overall avoided cost models.

Generation Emission Rates

Our team calculated average emissions rates using publicly available generating plant permit data such that if a major technology shift occurs in the future, this information can be readily updated. We compiled the reported and permitted emission rates for NOx and PM-10 for over 15 plants in California included emission estimates for aging plant in California.[43] Since emission rates vary for both NOx and PM-10 depending upon the operating configuration and the type of abatement control technologies installed on the generating system, we addressed each of these separately in our analysis. We determined the CO_2 emissions rates using the implied heat rate of the plant at the margin in any given hour. It was possible for us to calculate CO_2 emissions this way because the emissions are a direct function of the fuel type employed. No abatement technology exists for CO_2, and combustion of natural gas is independent of plant configuration other than efficiency. Additionally, generation plant emission rates do not vary in a consistent pattern for plants in different climate zones or regions so we elected to exclude

[43] See Appendix B for references to generation plants reviewed in this analysis

Estimating the value of CO_2 emissions is the most subjective element to this analysis because no market exists in California to capture this "unpriced" emission or externality. Therefore, we looked to publicly available data in regional markets such as Oregon and the Oregon Climate Trust, PacifiCorp's Integrated Resource Plan, and other state values of CO_2. Additionally, we evaluated many of the existing technical-economic and macroeconomic models for estimating the price of CO_2 credits as a result of the pending implementation of the Kyoto protocol in Europe and effects of United States participation. A more detailed discussion of the models and our conclusion is included in Section 2.4.4. However, our initial estimate of the CO_2 value in 2004 is $8/ton CO_2. Table 12 shows the price estimates used in our analysis through 2010 in $/lb CO_2.

Table 12: CO_2 price estimates through 2010

CO2 Price Estimates	*2004*	*2005*	*2006*	*2007*	*2008*	*2009*	*2010*
($/lb)	$ 0.004	$ 0.004	$ 0.004	$ 0.005	$ 0.005	$ 0.005	$ 0.005

Natural Gas End-Use Emission Costs

The emission costs for gas end-use consumption are "unpriced" externalities in this avoided cost model because most end-users are not required to outright purchase credits to offset their gas consumption and thus it is not a direct cost or "priced" emission in our model. We applied the same market prices for calculating the consumption emission costs as we do for the generation emission costs as discussed previously in this section.

Emission Rates and Costs

Finally, prior to including the emissions values in the overall avoided cost model, we simply multiplied the emission rates by the estimated emission cost per pollutant. We summed these values based on plant heat rate for the base year of 2004 to arrive at the values shown in Figure 30. Because the CO_2 emission rate is significantly higher than the NOx and PM-10 emission rates, the slope appears linear with respect to heat rate.

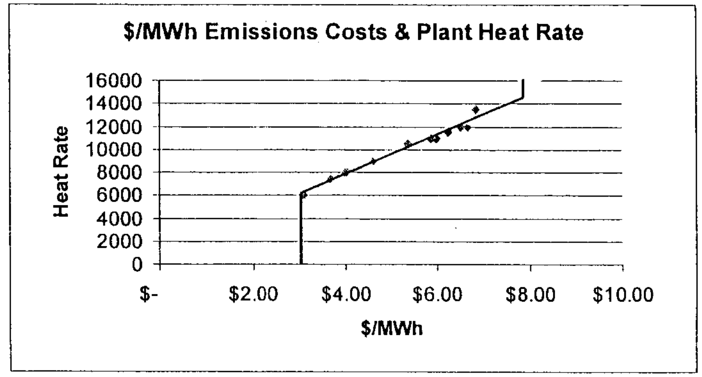

Figure 30: Emission costs ($/MWh) and plant heat rate for base year (2004)

When incorporating emissions avoided costs into the model, we specified a heat rate floor and ceiling that mirror the average range of operation for generating plant efficiencies. These are flexible boundaries whereby the heat rate floor and ceiling can be shifted over time as efficiency improvements in the generation technologies or generating plant mix changes occur. In each case, the cost of emissions associated with the floor or ceiling heat rate is used for any implied

How to keep the power flowing

Jul. 11, 2004 12:00 AM

The advent of the American Industrial Revolution and discovery of oil in Titusville, Pa., in 1859 is not coincidence. Ever since, energy and technology have been amorous dance partners, mutually dependent and more alluring as a pair than apart.

But occasionally, one steps on the other's foot, as with California's energy crisis, the 2003 East Coast blackout and Arizona's gasoline trauma.

The same is true of the current situation, as the July 4-5 fire at APS' Westwing substation imperils transmission of electricity into greater Phoenix. We hope Westwing promptly returns to service and our lives are not disrupted by planned outages ("rolling blackouts").

To accomplish one of its central missions of ensuring that Arizonans get "adequate, economical and reliable electric power," the Corporation Commission supervises biennial electricity generation and transmission assessments in cooperation with providers (investor-owned, public and cooperative), ratepayer, environmental and other constituencies. The task is complex.

Californians learned to their chagrin, after 20 years of adding zero power plants and few transmission lines, that electricity for latte machines does not come from the wall socket. But excess plants and transmission impose unnecessary burdens on both environment and ratepayers.

Consider this: An absolutely "failsafe" transmission system that could account for a Westwing-type disaster plus another high-voltage line failure requires inordinate expense to ratepayers. Someone must pay for facilities and un-aesthetic clutter of towers, poles and lines.

Like most governmental functions, the key is to balance competing interests. My colleagues on the commission and our predecessors have accomplished this objective. Our electricity system is robust. To survive a disaster like Westwing is testament. And unlike every other state in the interconnected Western grid, prices stabilized - and in APS and Tucson Electric Power service territories, even declined.

Government should be about fixing things, so let's examine the problem and posit progressive and constructive answers. Here's what we can do to prevent future (and inevitable) unforeseen events from disrupting our essential energy supplies.

Supply side

The Westwing problem is not supply of electricity, but transmission capacity into population centers. With notable but very important exceptions, power plants have and will be built in remote locations.

As a community, we must come to grips with the need for infrastructure. I actually got a call from a New Yorker opposing a needed West Valley transmission line because it traversed vacant land he had just purchased at a foreclosure sale.

Even acknowledging his land was in a designated utility corridor and that failure to build the line could result in blackouts did not stop this absentee landowner's zeal for turning dirt into cash. This was not a civic-minded citizen fighting to preserve neighborhoods. Hopefully, the California and East Coast blackouts have driven a stake through the heart of mindless NIMBY-ism.

Demand side

Worldwide commodity costs have dramatically risen for electricity, petroleum and natural gas. We cannot drill our way out of this predicament. We must reduce both energy consumption and our use of fossil fuels.

• Commission workshops have examined exciting technologies to reduce overall energy consumption and shift demand to off-peak hours. New strategies allow computerized climate-control to save consumers money. Funding of old-fashioned weatherization programs should be increased as well.

• Again, technology is an ally. Solar- and wind-powered micro-generators added to the grid reduce dependence upon fossil fuels and remote transmission, save money and clean the air.

• In 2001, the commission adopted rules mandating electricity generation from renewable sources. Higher fossil fuel costs and technological advances make clean energy more cost-effective. Funding for this program should be increased. Also, the rules should engender healthy competition among solar, wind and biomass technologies.

The Internet and other innovations have massively changed and improved our lives. But we remain ever dependent upon energy, and the dichotomy of reliability and price pull in opposite directions. We as a community must recognize 1) We are in this together; 2) infrastructure is essential and 3) technology properly used protects the environment and lowers costs for consumers. The dance goes on.

Marc Spitzer is chairman of the Arizona Corporation Commission.

July 19, 2004

Saving a Little Available Light

By Patti Harper-Slaboszewicz
Director, AMR and Demand Response

What are demand response (DR), demand side management (DSM), and energy efficiency (EE), and how does one distinguish one from the other? I would suggest that it will become more and more difficult to make a distinction. Consider the Virtual "Negawatt" Power Plan (VNPP®) offered by Electric City, which uses energy efficiency gains in lighting to provide DSM to utilities. Alternatively, the technology could also be used by retail customers or Electric City to bid DR load into the energy markets. Thus, the level of load available for DSM or DR from energy efficient lighting is not limited to the interest of utilities in DSM.

Electric City has created an innovative EE/DSM/DR product that is attractive to utilities and to retail customers alike based on controlling lighting rather than temperature sensitive loads such as air conditioning (A/C) or heating. Denis Enberg, the Senior VP of Engineering of Electric City said "We term our equipment as a base load demand side management tool that is predictable, measurable and verifiable." Commonwealth Edison (ComEd) in Illinois has entered into an agreement with Electric City to provide 50 megawatts (MW) of DSM load to the utility by signing up retail customers in the Chicago area. So far Enberg estimates Electric City might be up to 25 MW. In the VNPP program, retail customers face no penalties, have zero upfront costs, enjoy consistent and predictable savings on energy costs, and participation has little or no impact on the customers' business. Business goes on as usual, even during DSM events.

ComEd can select to drop load to one feeder, a substation, or to any portion of its territory served by one or a group of distribution or transmission assets in the service territory. If there is local congestion, ComEd can reduce loads only in the congested area. If there is a major problem, such as a nuclear plant dropping off the grid, the utility can quickly reduce load across its entire service territory.

Because lighting load is a base load that is very predicable throughout the year, ComEd can quickly ascertain the amount of load reduction available. The equipment installed by Electric City at the customer locations measures the lighting load on a near real time basis (every fifteen minutes).

VNPP provides both the retail customers and the utilities with a program that meets their needs. Customers are attracted to the predicable energy savings that are not dependent on the utility calling DSM events. There is virtually no risk for the customers to participate. If the customer agrees to participate and decides to withdraw (so far no customer has opted to do this), Electric City will remove its equipment and place it with another customer. If the utility did not need the load reductions, the customer would still enjoy the energy savings from the energy efficient operation of its lighting system.

When a customer agrees to participate in VNPP program sponsored by ComEd in the

Chicago area, Electric City installs one or more EnergySaver devices to control the lighting in a building or customer location, and one GlobalCommander. The customer lighting load is coded to identify which transmission and distribution assets service the customer. This allows the utility to determine the available load for curtailment down to the feeder level, and to reduce load strategically in the service territory.

Electric City will work with the building managers at each location to establish the lighting level for normal business operations (called the conservation level), and the lighting level the customer can live with during an event. However, Enberg noted that most customers can not tell when an event is occurring. He said that one of the beauties of working with lighting is that it is very difficult even for a trained eye to note the change in lighting level. Electric City does not turn lights on and off. Rather, their equipment changes the lighting level evenly throughout the facility. This allows the retail customer to participate in events and continue operations.

For long term participation in DSM or DR, Utilipoint believes the key is to establish programs whereby the economic cost is minimized for the ultimate providers of the DSM or DR load, the retail customers.

On the utility side, the utility wants firm load reductions. With this system, the utility almost has it all. The utility will know how much load can be dropped, controls the load drop, and can reduce load strategically according to its needs. The utility will still pay "reservation" costs indirectly through the savings on lighting that the customers enjoy whether or not the utility needs to invoke the VNPP. Based on the interest in the VPNN product from the utility side, this has not been a deterrent. Three utilities (ComEd, Xcel, and Enersource) have so far signed agreements or the intent to do so, and there are at least ten others in serious discussion with Electric City.

The potential for retail customers to game the system has always been a worry for utilities and regulators in the development of any DSM/DR program. Electric City has tried to forestall this by logging each activity initiated through its devices. The actual specifics of the VNPP programs may vary from one service territory to another, but Enberg noted that the software will not allow a customer go move from a conservation level to a full level back to the DR level. In the ComEd program, the utility controls the lighting levels in the customer facility, significantly reducing the opportunity for gaming.

During a DSM/DR event, the equipment logs five different pieces of information for each event:

- Beginning and ending time of the event;
- Demand in kW just prior to the event;
- The demand in kW during the event (set to one level for the entire event);
- The avoided demand (the prior kW minus the kW during the event);
- The avoided kWh usage during the event.

These calculations are relatively easy because the curtailment takes place on a lighting load, which is a steady load for each preset lighting level. There should be little controversy in terms of how much load reduction was provided to the utility since the lighting loads are steady prior to the event and during the event.

Electric City is actively wooing retail customers with multiple locations across North America. The idea is that if a retail customer has a good experience with the VNPP program in one utility service territory, it should less costly to sign up the same customer in a different utility service territory. This should increase the interest on the utility side of the market, and reduce customer acquisition costs on the retail side.

Home Depot, Dean Foods, Heinz, Galvans, and Meijers have all signed up to participate in the Chicago area for the VPNN program for ComEd. If more customers are interested in the VNPP program than needed to provide the 50 MW to ComEd, customers have other options. Electric City could provide the equipment to a customer and the two parties could negotiate an agreement as to the energy savings enjoyed by the customer and the financing of the equipment.

Since ComEd is a member of PJM, customers that do not participate in the ComEd VNPP program (or any other VNPP program) could bid the load reduction gained from dropping the lighting level to the DR level into the energy markets operated by PJM. If the customer is not comfortable bidding into the market itself, then Electric City could aggregate the DR load with other eligible customers in the PJM region. With an investment of zero dollars, large retail customers could save up to 5% on the energy to light up the business indefinitely. If the load reduction from dropping to the DR level of lighting is bid into an energy market, the customer could earn still more. Clearly, Electric City is onto something here.

How big is this market? The most recent Energy Information Administration (EIA) Annual Energy Outlook forecasts 1.17 Quadrillion BTUs per year in 2004 for commercial lighting from purchased energy. Converting this to an average MW load for commercial lighting yields an average commercial lighting load of 39,000 MW. Assuming a conservation level of 15% of this average light load would suggest the market size is at least 5,800 MW. This would be equivalent to 1.5 Palo Verde Nuclear generation plants.

WESTERN RESOURCE ADVOCATES
PROPOSED CHANGES IN DEFINITIONS
July 22, 2004

Key Terms

adjustment mechanism: a provision of a rate schedule, authorized in advance by the Commission, which allows for increases and decreases in rates reflecting increases and decreases in specific costs incurred by a utility. Adjustments in rates may require Commission approval or they may be automatic and not require Commission approval. ~~a tariff provision, approved in advance by a regulatory commission, in which a change in a preselected cost item or items will automatically permit a change in the price charged consumers, without the delay and expense of a formal regulatory hearing.~~

incremental costs: the additional cost of demand side management programs and measures relative to baseline cost. Incremental cost includes the additional cost of more efficient measures (whether paid for by utilities, participants, or others), the additional cost of market transformation activities, and additional administrative costs incurred by a utility ~~utility costs of~~ implementing demand-side management programs in excess of those costs which are otherwise recovered in rates.

market transformation: strategic efforts to induce lasting structural or behavioral changes in the market that result in increased adoption of energy-efficient technologies, services, and practices.

net benefits: ~~costs:~~ ~~incremental costs minus~~ avoided energy, ~~or~~ capacity, and other costs ~~costs that the utility recovers through rates which are not changed between rate cases as a~~ resulting ~~of~~ from demand-side management minus the incremental costs of demand side management.

Societal Test: a cost effectiveness test of the ~~a cost-effectiveness test~~net benefits of DSM measures and programs that starts with the Total Resource Cost Test but includes ~~impacts on~~non-monetary (or non-market) benefits to society, such as reduced environmental effects of electricity production and delivery, due to DSM. ~~externalities, and~~The Societal Test employs ~~uses~~ a ~~societal~~ social discount rate.

Do we know what a societal or social discount rate is?

Total Resource Cost Test: a cost-effectiveness test of the net benefits of DSM measures and programs.~~that measures the net costs of a DSM program as a resource option based on the total costs of the program, including both participant and utility costs.~~

Utility Cost Test: a cost-effectiveness test that measures the net change in a utility's revenue requirement resulting from a DSM program. The test compares the reduction in marginal energy and demand costs with utility program costs, incentive payments, and increased supply costs for a period in which load is increased. This test does not include any net costs incurred by participants.